SILVESTRINI

KEYSPAN ENERGY DELIVERY NEW ENGLAND

Direct Testimony of A. Leo Silvestrini

Exhibit KEDNE/ALS-1

D.T.E. 03-40

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is A. Leo Silvestrini. My business address is 52 Second Avenue, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am the Director of Rates and Regulatory Affairs for KeySpan Energy Delivery New England ("KEDNE"). As the Director of Rates and Regulatory Affairs, I am primarily responsible for supervising the design, implementation and administration of the Company's rates, tariffs and cost studies, as well as preparing, coordinating and supervising testimony on rates and forecasting matters before state regulatory commissions. I am also responsible for the analytical functions related to forecasting customer demand, revenues and gas costs. I perform these activities on behalf of KeySpan's New England local distribution companies, including Boston Gas Company d/b/a KeySpan Energy Delivery New England ("Boston Gas" or the "Company").

Q. Please briefly describe your educational background and business experience.

A. I received a Bachelor of Arts Degree in History in 1973 from the State University of New York at Albany and a Master of Arts Degree in Economics from Tufts University in 1976. I also received a certificate from the Northeastern University

School of Business Management for the completion of the Management Development Program in 1987. In 1978, I joined Boston Gas as an economic analyst in the Rate Department. In 1980, I was promoted to Manager of Rates and Revenue Analysis, and in 1985, to the position of Director of Rates and Economic Analysis. Over the next several years, I held a similar position in Market Planning and Development, Corporate Strategic Planning and Gas Resource Planning. In 2000, I was named to my current position, Director of Rates and Regulatory Affairs. I am a member of the American Gas Association, the Northeast Gas Association and the New England Chapter of the International Association of Energy Economists.

Q. Have you previously testified before the Department of Telecommunications and Energy or any other regulatory agency?

A. Yes. I have testified in several regulatory proceedings before the Department of Telecommunications and Energy (the "Department"). For example, I testified in Boston Gas Company, D.P.U. 88-67 (1988), Boston Gas Company, D.T.E. 97-81 (1999) and KeySpan Energy Delivery, D.T.E. 01-105 (2002), involving the Company's most recent Long Range Resource and Requirements Plans. I have also testified in several proceedings before the New Hampshire Public Utilities Commission on behalf of EnergyNorth Natural Gas, Inc., which operates as part of KEDNE. These proceedings include Docket DG 00-145 regarding the Company's request for approval of certain agreements with AES Londonderry, LLC, DG 00-063 regarding rate redesign issues, DG 01-021 regarding the

Company's revised Winter 2001 cost of gas, and all of the Company's subsequent cost of gas proceedings.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of Boston Gas on the Company's marginal cost study, rate-design issues and proposal to establish a Weather Normalization Clause.

Q. Please describe the exhibits attached to your testimony.

A. My testimony is supported by the following exhibits:

KEDNE/ALS-2	Marginal Cost Study
KEDNE/ALS-3	Revenue Requirement Worksheets
KEDNE/ALS-4	Rate Design Worksheets
KEDNE/ALS-5	Customer Bill Impacts
KEDNE/ALS-6	Weather Normalization Schedules
KEDNE/ALS-7	Rate Tariffs

Q. How is your testimony organized?

A. The remainder of my testimony is organized into the following three sections. Section II sets forth the Company's marginal cost study and discusses the results of that analysis. Section III reviews the Company's rate-design approach and customer bill impacts. Section IV describes the Company's proposal to establish a Weather Normalization Clause.

II. MARGINAL COST STUDY

Q. Would you briefly describe the methodology used in the development of the Company's Marginal Cost Study?

A. In this filing, the Company has completed the marginal cost study (the "MCS") using the methodology approved by the Department in Boston Gas Company, D.P.U. 96-50 (Phase I) (1996) ("D.P.U. 96-50"), and in the Company's prior rate proceeding, Boston Gas Company, D.P.U. 93-60 (1993) ("D.P.U. 93-60").

Q. Would you provide an overview of the MCS?

A. The MCS is designed to analyze the increased non-gas costs that the Company would incur if it were to expand its services through the addition of distribution capacity, the addition of customers, or the increased throughput of natural gas. Marginal capacity costs are the variable costs that the Company would incur in the long run to meet increased demands on its system capacity during peak periods. The MCS also analyzes the costs that would be incurred by adding an additional customer to the Company's system, such as the cost of adding a service, a meter and the increased billing costs required to serve the new customer. Lastly, the MCS analyzes the costs to serve an additional unit of throughput.

Q. How does the Company approach the rate-design process?

A. The Department has identified five rate-structure goals that the Company considers in designing rates. These goals are efficiency, simplicity, continuity, fairness and earnings stability. In order to promote the Department's rate structure goals, the Company's rate design must satisfy two objectives. First, the rate design must set rates for each rate class that produce sufficient revenues to cover the allocated cost of serving that class, unless a different revenue target has been determined to be appropriate for reasons of rate continuity. Second, to the extent possible, the rate design must be based on marginal costs, i.e., the incremental cost to a utility of producing one additional unit of output. The end result of this approach is that customers receive a fair price for the services that they require and a more accurate price signal to guide consumption decisions.

To achieve a rate design consistent with these goals, the Company follows five steps. First, the Company performs an allocated cost-of-service study to assign revenue and a portion of the Company's total cost of service to each rate class. Second, the Company performs the MCS to determine its incremental costs. Third, the Company converts marginal costs into rates for each rate class. Fourth, the rates set at marginal costs are reconciled with the revenue requirement for each customer rate class. Fifth, the resulting rate structure is compared to existing rates. If the Company finds that the resulting rate increases are too great for some customers, then it may require the rate design to be adjusted to move rates toward marginal costs in a way that is more consistent with the goal of rate continuity.

Q. How does the MCS assist the Company in meeting the Department's rate-structure goals?

A. The Cost of Service Study (the "COSS"), presented in Ms. Leary's testimony, and the MCS are both necessary tools in designing rates. The combination of the COSS and the MCS allow the Company to design rates that: (1) collect the

Company's revenue requirement in a manner consistent with the costs imposed on the system by individual customer classes, and (2) send accurate price signals to customers to guide their consumption choices. The COSS establishes the total cost of serving each of the Company's existing rate classes. By determining the cost of service to each customer class, the Company can identify the total revenues that must be obtained from each of those classes in order to ensure that there is minimal or no cross-subsidization between classes and that parity between the rate classes is maintained.

The MCS is used in conjunction with the COSS to set rates because it identifies the additional cost that would be imposed on the system if new customers, throughput or system capacity were added in the future. Setting rates to reflect the marginal cost of additional customers, load or system capacity sends a more accurate price signal to customers in terms of the cost of their consumption in different time periods. For example, a greater percentage of distribution-capacity costs should be reflected in the peak-period rate to reflect the fact that there is greater usage of system capacity during the peak period.

Q. What time periods did the Company use to evaluate incremental costs in the MCS?

A. Three different time periods were used in the MCS, with each time period appropriate for different purposes:

1. the design day;
2. the six winter months of November to April; and
3. the six summer months of May to October.

The design day is used to measure peaking capacity costs, which is appropriate because the Company's planners utilize the design day as the primary planning criterion for decisions concerning production and distribution capacity. Based on the weather-sensitive nature of customer loads, the Company estimates and plans to meet the sendout requirements of its customers under the extreme temperature conditions of a design day. However, the design day is not to be confused with the peak day. The "peak day" is the day each year during which the Company experiences the greatest amount of customer load on its system. The "design day" represents the coldest day for which the Company plans to have the capability to meet customer loads.

Space heating is the end-use that places the greatest demand on the Company's distribution system. Therefore, the winter-heating season is the period when gas-distribution loads increase and weather conditions provide the impetus for demand. The summer season represents the period of the year when temperatures and gas distribution sales and sendout reflect usage that is primarily "baseload" in nature. As a result, these seasonal periods are related to cost causation on the Company's system. For the MCS, the Company has chosen the seasonal periods that coincide with those reflected in the COSS, the Company's current base rates, and the Cost of Gas Adjustment ("CGA") factor.

Q. Would you please identify the schedules that are used in the Company's MCS?

A. The schedules composing the MCS are set forth in Exhibit KEDNE/ALS-2. My testimony discusses each of the schedules in turn.

Q. Would you please comment on Schedule 1 of the MCS?

A. Schedule 1 develops system-capacity costs for investments in the Company's distribution system. Marginal distribution capacity costs consist of the long-run marginal cost of upgrading the existing transportation and distribution ("T&D") system and the cost of main extensions to add new load to that system. For this exercise, the Company uses the prospective additions method approved by the Department in D.P.U. 96-50, at 150-151, and D.P.U. 93-60, at 375-376 to estimate the marginal costs of reinforcing the existing system to meet expected future growth. To estimate the cost of expanding the system to meet growth, the Company analyzed these costs over the most recent four year period.

Q. Would you please explain the analysis presented in Schedule 1 in more detail?

A. Marginal distribution capacity costs consist of two elements, i.e., the long run marginal cost of reinforcing or upgrading the existing T&D system, and the long-run marginal cost of installing new main extensions to add load to that system. To perform the calculation for the first element, the Company uses Network Analysis, which is an engineering evaluation tool that identifies the need for system reinforcements to maintain system pressures and support capacity growth. The results of this analysis are presented on Schedule 1 at page 2. The analysis projects a five-year load-growth pattern and assumes that the projected growth will occur on a uniform basis throughout the Company's system. The load-growth projection is consistent with the growth presented in the Company's Long Range Resource and Requirement Plan, approved by the Department in KeySpan Energy Delivery New England, D.T.E. 01-105 (2003). Based on the load-growth projection, the analysis identifies the locations on the system where existing facilities would have to be upgraded to account for that growth. More specifically, the analysis identifies the upgrades necessary to accommodate additional peak-hour load, estimates the cost associated with the reinforcement upgrades and calculates the unit cost per MMBtu of design day growth. In this case, the analysis shows a long-run reinforcement cost of $142.17 per design day MMBtu.

The second element, the cost of growth-related main additions, is derived on Schedule 1, at page 3. As with reinforcement costs, the Company determines the main extension cost per design day MMBtu. This figure is derived from the weighted cost per foot of mains added over the last four years and the number of feet required for each additional design day MMBtu. In order to set forth the Company's marginal cost, this figure is then reduced to reflect any customer contributions toward the cost of the main extension required by the Company.

This analysis shows a long run marginal cost of $356.98 per design day MMBtu for growth-related new main additions. The marginal capacity-related costs attributable to system reinforcement and to new mains extensions are totaled on

Schedule 1, page 1, line 13. In this case, the analysis shows a total long-run marginal capacity-related distribution cost of $499.15 per design day MMBtu.

Q. Would you please discuss Schedule 2?

A. Schedule 2 also involves plant (or capital investment) costs. However, where Schedule 1 calculated capacity related distribution-plant investments, Schedule 2 addresses customer-related service and meter investments.

Specifically, Schedule 2, page 1 sets forth "services" costs, i.e., the cost of the line from the Company's main in the street to the customer's building. Schedule 2, page 2 sets forth the metering costs. The data is taken from the Company's marketing information system or work-load management system and is disaggregated by rate class. In the case of service costs, the required customer contribution for the Residential Non Heating class is deducted from the Company's marginal cost. The Company generally requires a new customer in this class to pay the full cost of a new service installation because the loads and revenues from a residential non-heating customer are so low.

Q. Would you please discuss Schedule 3?

A. Schedule 3 is the first of three schedules that calculate marginal operating expenses. Schedule 3 deals with the marginal operations and maintenance ("O&M") expenses associated with capacity-related production.

Q. Where are the marginal capacity-related production expenses calculated?

A. The capacity-related production expenses are derived on Schedule 3. These costs are carried forward to Schedule 3, page 1, where a factor is applied to convert the expenses to 2002 dollars, using the Gross Domestic Product -- Implicit Price Deflator ("GDP-IPD"). For this analysis, the Company made several calculations. Specifically, the analysis included a regression of adjusted expense dollars against design-day data; trended costs over 26 years; and average cost data over several different periods. Based on these analyses, and the statistical results produced, the Company determined that the current 2002 test-year average cost per design day MMBtu of $0.83 most accurately reflects marginal capacity-related production costs.

Q. Would you discuss Schedule 4?

A. Schedule 4 develops transmission and distribution O&M expenses, and in particular, develops marginal-cost figures for the portions of those distribution expenses that are capacity-related and for the portions that are customer-related. Schedule 4, at pages 2 and 3, displays transmission and distribution expenses as reported in the Company's DTE Accounts for years 1988 through 2002 (the full database includes 1977 through 2002), and classifies those expenses as capacity-related, customer-related, or non-marginal. For example, capacity-related operating expenses include Account 851 (System Control and Load Dispatching) through Account 857 (Measuring and Regulating Station Equipment), while customer-related operating expenses include Account 878 (Meter & House Regulator Expenses), Account 879 (Customer Installation Expenses) and Account 892 (Maintenance of Services). Some accounts, such as Account 874 (Mains and Services Expenses) include both capacity-related and customer-related elements.

Therefore, these accounts were allocated on the basis of the relative plant investments during the respective year in Mains and Services, with the mains being capacity-related and the services being customer-related. In addition, some accounts, such as Account 881 (rents) were assumed to be non-marginal. Accounts 850 and 885 (Supervisory and Engineering Expenses) were allocated to the capacity, commodity, and non-marginal categories on the basis of the other T&D O&M expenses.

After allocation, the resulting customer-related T&D expenses are derived on Schedule 4, pages 2 and 3, line 40. This data is utilized in Schedule 5 to derive total customer-related expenses.

The resulting capacity-related distribution expenses are derived on Schedule 4, pages 2 and 3, line 44, with this data carried forward to page 1 of the schedule. These annual expenses are converted to current dollars using the GDP-IPD, and then divided by peak-day sendout to arrive at a unitized cost per peak day. Peak day sendout was used to develop this unitized cost because O&M expenses are more likely to vary with the peak actually experienced rather than the design day used to determine the planning-capacity investment.

The analysis included a time-series estimate; trended costs over 26 years and average cost data over several different periods. Based on these analyses, and the statistical results produced, the Company determined that the average cost per peak day over the last five years is the most representative of the Company's marginal cost because it smoothes the variations in recent annual average costs.

Q. Please explain the computation of marginal customer-related expenses.

A. These expenses are derived in Schedule 5 and include three categories of customer-related operating expenses: (1) distribution-system expenses, (the maintenance of services and meters), which were derived in Schedule 4; (2) customer-related accounting and marketing expenses; and (3) uncollectible accounts.

Q. Would you first describe the derivation of customer-related distribution expenses?

A. Customer-related operating expenses associated with the distribution system are addressed on Schedule 5, pages 1 and 2. On page 1, annual customer-related service and meter expenses, derived from Schedule 4, pages 2 and 3, line 40, are converted to 2002 dollars using the GDP-IPD. The analysis included a time-series estimate; trended costs over 26 years; and average cost data over several different periods. Based on these analyses, and the statistical results produced, the Company determined that the average cost per customer in 2002, or $57.64, is most representative of the Company's current marginal cost for customer-related distribution costs. Schedule 5, page 2 converts the total Company average cost per customer by rate class using the customer costs assigned in the allocated cost of service study ("COSS"), Exhibit KEDNE/AEL-5.

Q. How are customer-related accounting, marketing and uncollectible account expenses derived?

A. These expenses are derived on Schedule 5, pages 3 through 6. Page 3 presents a time-series regression analysis for customer accounting and marketing expenses, with the underlying data derived from the Company's DTE Accounts, converted to 2002 dollars using the GDP-IPD. The Company used the 2002 average cost of $57.64 because it best represents the Company's marginal customer-related accounting and marketing costs. Page 4 allocates this overall average cost by customer class, in accordance with the Company's COSS presented in Ms. Leary's testimony. Uncollectible accounts are computed and allocated in a similar fashion on pages 5 and 6 of the Schedule 5. The Company used the current average cost of $11.37 from the 2002 test year for the Company's marginal customer-related uncollectible cost.

Lastly, the class-specific accounting, marketing and uncollectible marginal costs are totaled in Schedule 5, page 4, column 8.

Q. Would you please summarize what the marginal cost analysis has shown to this point?

A. At this point in the analysis, the Company has derived various marginal plant investment costs in Schedules 1 and 2 and various marginal expense items in Schedules 3, 4, and 5. Each of the investment costs and marginal-expense items have been classified as capacity-related, commodity-related, or customer-related, and allocated to various rate classes where appropriate. To reflect the true marginal cost, the Company now has to increase those marginal costs by various loading factors, which reflect administrative and other indirect expenses that will increase proportionately with increases in direct labor expenses or plant investment costs. The Company also has to develop fixed-charge rates, which will enable the conversion of capital investment costs into annualized depreciation, property tax, interest, return and income tax figures for use in the marginal cost analysis. The Company will then sum the various expenses and annualized capital investment costs, as allocated.

Q. **How are the loading factors derived?**

A. The various loading factors are derived in Schedule 6. Schedule 6, pages 1 and 2 develop the loading factors for administrative and general (A&G) expenses, which are indirectly attributable to changes in load. Certain A&G expenses (the largest being pension expenses) are classified as labor-related; others (the largest being property insurance) are classified as plant-related.

Additional loading factors are derived on Schedule 6, at pages 3 and 4. The loss-adjustment loading factor accounts for system losses and is derived by comparing billed sales and transportation therms to total throughput. The non-fuel loader accounts for materials and supplies and prepayment expenses (other than for fuel inventories), while the general plant loading factor accounts for general and intangible plant investments. Both the non-fuel and general plant-loading factors are used for plant investments in developing capacity-related and customer-related marginal costs.

Q. In general, how are the fixed-charge rates derived?

A. The fixed charge rates are derived in Schedule 7. As I explained earlier, it is necessary to spread large, one-time investments in distribution plant, plus services and meters installed over time, into annual revenue requirements in order to include them in the marginal cost. In calculating the annual revenue requirement, the Company determines the present value of all costs incurred from the ownership of an asset and then calculates the level of the annual payments necessary to yield an amount equal to present value of all the costs. The calculation of revenue requirements takes into account not only the initial purchase price of the asset, but also assumes a useful life, a salvage value, a projected inflation rate, property taxes and income taxes and cost of capital.

The discount rate that is applied to future revenue requirements is the Company's weighted cost of capital, or 10.13%, as presented in this case, weighted to account for the proportions of debt, preferred stock and common stock. This figure is reduced by deductible interest expenses and increased to account for taxes on equity income.

Schedule 7 presents two types of fixed charge rates, i.e., the "banker's" rate and the "economist's" rate. The "banker's" rate is similar to a fixed-rate mortgage with equal annual payments. This rate is the percentage of the original plant investment that would have to be collected in each year in order to recover the revenue requirements over the life of the plant investment. The "economist's rate" differs slightly because it assumes that payments will escalate in each year with the rate of inflation. As a result, the economist rate in the initial year, shown in Schedule 7, is lower than the banker's rate, although it escalates to a higher figure by the end of the lifetime of the plant investment.

Q. What is the discount rate that is used in the marginal cost study?

A. As in D.P.U. 96-50, the Company has chosen the "economist's" rate because it more closely represents the actual useful lives of the Company's fixed assets. The "banker's" rate, with equalized discounts over the years, implicitly assumes that an asset with, for example, a 20-year life, is significantly less useful in year 20 than in year 1. Thus, the value of the asset is depreciated significantly more at the beginning of its useful life and less at the end, offsetting the increased "interest" component in later years. In fact, the Company's fixed assets are nearly as useful at the end of their useful lives as at the beginning. This is reflected in the "economist's" rate, which inflates over the years to reflect the increased "interest" component attributable to later years.

Q. Are the same rates applied to all plant investments?

A. The rates will vary depending on the assumed useful life and the assumed salvage value of each type of plant investment. For example, as shown on Schedule 7, page 1, the "economist's" rate is 10.79% for a metering investment, but only 9.59% for capacity-related distribution investments.

Schedule 7, at page 14 shows the derivation of the weighted plant lives and salvage values for each of three categories of plant investments, i.e., distribution plant, services and meters. Schedule 7, pages 2 through 13 show the derivation of the levelized fixed charge rates for each of the three categories.

Using distribution plant as an example, Schedule 7, page 2, shows the input assumptions, including service life, salvage value, capital structure and the cost, tax and inflation data, used to develop the rate. Pages 3 and 4 show the calculation of annual revenue requirements necessary to cover the required interest payments, return on equity, depreciation, and tax payments. The present value of this stream of annual revenue requirements is calculated by using the Company's opportunity cost of capital, which is the weighted cost of capital reduced by the deductible interest expense. Page 5 summarizes the calculation of the "banker's" rate and the "economist's" rate for capacity related distribution plant.

Q. **Would you please review the schedules that summarize the marginal cost study?**

A. Schedule 8 summarizes marginal capacity costs and Schedule 9 summarizes marginal customer costs. These costs are combined in Schedule 10 and presented as unit costs in Schedule 11.

Q. **Please explain Schedule 8.**

A. As I stated above, Schedule 8 summarizes marginal capacity costs. The first element, derived in page 1, lines 1 to 9, reflects marginal capacity-related investments for distribution plant (along with loading factors) annualized through use of the "economist's" rate. On lines 11 through 15, the Company shows how it has added to this element the marginal production and distribution capacity-related operating expenses. On lines 17 through 23, the study adds working capital. These costs are then adjusted for the system loss factor (line 28) and inflation (line 29) to derive the total seasonal capacity cost shown on line 31.

Q. Schedule 9 develops the marginal customer costs. Would you please identify the elements that constitute those costs.

A. As with the marginal capacity-related costs, the Company has both plant investments, which have to be annualized, and operating expenses. Both components are adjusted for loading factors, working capital requirements and inflation. The marginal customer-related cost is reported by rate class and shown as an annual cost on line 38.

Q. What is the purpose of Schedule 10?

A. Schedule 10, page 1 and 2 summarize the two different components of long-run marginal cost, which are computed in the two prior schedules. In addition, these pages at the lines 26 through 41 set out the revenues that would be derived from full marginal cost pricing, i.e., if all prices were set equal to marginal cost. This latter calculation assumes that current billing determinants (set forth on Schedule 10, page 3, and on pages 1 and 2, lines 18 to 21) did not change.

Q. What is the purpose of Schedule 11.

A. This schedule derives the marginal unit cost per MMBtu of gas sold. The capacity-related charges, which were derived as $/design day MMBtu, have to be converted to $/MMBtu in order to be usable for the purposes of setting rates. The result is shown on line 6. This calculation is made in Schedule 11 for each of the rate classes using test year billing determinants.

Q. Would you explain how the results of the MCS were incorporated into the rate-design methodology?

A. Yes. The results of the MCS, shown on line 8 of Schedule 11 for each rate class, are used to establish the tailblock rates for each season for each rate class. In this way, the rate design gives customers the proper price signal when they decide to consume more or less gas in a given season.

III. RATE DESIGN

Q. Please provide an overview of the Company's rate design proposal.

A. As discussed above, the Company has designed rates to be consistent with the Department's rate-structure goals of fairness, efficiency, simplicity, continuity, and earnings stability. In keeping with those rate-structure goals, the Company is proposing to phase in cost-based customer charges to reduce intra-class subsidies. As demonstrated by the cost studies performed by Ms. Leary (Exhibits KEDNE/AEL-5 and KEDNE/AEL-6), none of the customer classes are paying their full embedded-cost customer charges. Therefore, all classes are recovering a portion of their allocated customer costs in the headblock rates, effectively shifting cost burdens from lower usage customers to higher usage customers, which violates the Department's goals of economic efficiency and fairness.

Therefore, to the extent possible, the Company has set the standard tariff tailblocks at the long-run marginal cost, as determined by the MCS. The

Company has also attempted to simplify rate structures. Because a single-step volumetric charge is simpler for customers to understand and is easier to administer, the Company has established single-step rates where possible. These simplifications are made easier as customer charges approach full cost. However, where customer costs are not fully recovered in the customer charge, the second best solution is to create a headblock or volumetric charge in a consumption block that does not distort the price signal of the tailblock. The creation of headblock rate, however, complicates the rate structure and moves it away from the principle of simplicity.

To promote efficiency, the Company has set the peak period tailblock rate at the marginal distribution cost. Consistent with Department precedent, the Company generally sets the break between headblock and tailblock rates at a level that results in approximately 50% of customer bills terminating in the headblock and 50% in the tailblock. In order to enhance the Department's goal of earnings stability, the Company set the off-peak tailblocks at levels that will ensure that a level of margin will be collected in the off-peak period.

The Company's rate design proposal allocates social subsidies created by the discount rates across the broadest base of core classes. These subsidies include the cost of providing low-income discount rates, which remain in the calculation of base rates. The recovery of DSM costs and manufactured gas remediation costs will continue to be recovered through the Local Distribution Adjustment Charge ("LDAC"), which is billed to all core throughput customers.

Q. Have you made any changes in the way that gas-supply related costs have been unbundled from distribution service rates?

A. In D.P.U. 96-50, the Department found that recovery of costs associated with local production and storage facilities should be allocated between base rates and the CGA, using a percentage split of 15% to base rates and 85% to the CGA. This allocation was intended to reflect the fact that, at the time, a portion of the Company's local production and storage facilities were being used to maintain system pressures for reliability purposes. Therefore, it was necessary to maintain a level of those costs in base rates to ensure that transportation-only customers had responsibility for their share of the local production and storage costs necessary to maintain system reliability. In this case, the Company has allocated 100% of production and storage costs to the CGA because these facilities are no longer used to support distribution-system integrity. Because of changes in the availability of new pipeline supplies and the enhanced reinforcement of its distribution system, the Company's local production and storage facilities are now used entirely for gas supply, peak-shaving purposes.

To accomplish this change, the Company conducted an unbundled cost-allocation study to determine the revenue requirement that is associated with these facilities. This amount has been deducted from the total revenue requirement to be billed through base rates and will be included in the CGA calculation. A revised Cost of Gas Adjustment Clause tariff incorporating this change is included in Exhibit KEDNE/ALS-7.

Q. Please identify the exhibits that set forth the Company's proposed rate design.

A. Exhibit KEDNE/ALS-3 provides the derivation of revenue requirements by rate class. Exhibit KEDNE/ALS-4 contains the rate-design worksheets for the proposed rates and Exhibit KEDNE/ALS-5 shows the customer bill impacts of the proposed rate design. These exhibits were used, in conjunction with the Company's unbundled COSS (Exhibits KEDNE/AEL-5 and 6), and the MCS (Exhibit KEDNE/ALS-2), to develop the rates proposed by the Company.

Q. Please comment on the overall structure of the Company's proposed rates, focusing first on the relationship between the base rates and the CGA.

A. The Company's CGA factor will recover all gas costs, including the cost of service associated with the Company's local production and storage facilities. The Company's base rates will recover distribution-system costs, including net income and the Company's return on rate base. Since base rates exclude gas costs but include the Company's income and return, the Company is financially indifferent in providing sales or transportation service to its customers.

Q. Please comment on the specific decisions made in designing individual class rates, beginning with the Residential Assistance Rates, R-2 and R-4.

A. The Residential Assistance Rates (Non-Heating R-2 and Heating R-4) provide a discount from the Residential Non-Heating (R-1) and Residential Heating (R-3) rates, respectively. The Company has calculated a discount of approximately 40% to maintain existing low-income subsidy levels. The Company accomplished this by reducing each component of rate R-1 and R-31 by 40%.

Q. Please discuss the Residential Non-Heating Rate (R-1).

A. For the R-1 rate class, the Company has increased the monthly customer charge from $8.48 to $10.45, which is below the full customer cost of $14.38, established by the embedded cost-allocation study (Exhibit KEDNE/AEL-5). This increase is necessary to reduce intra-class subsidies, i.e., the subsidization of low volume users by higher volume users and to improve the equity of the rate-design structure. However, to balance rate continuity with rate equity, the Company increased the customer charge by one-third of the difference between the current customer charge and the fully allocated customer costs. For consistency, the Company has applied this increment (1/3) to update the customer charges for each customer class in this case. The tailblock rate has been set at the peak marginal cost rate of $0.1438 per therm.

To keep the number of bills ending in the headblock close to 50%, the Company maintained the block break for the off-peak rates at 10 therms per month and for the peak rates at 20 therms per month.

Q. Would you comment on the Residential Heating Rate (R-3)?

A. The existing customer charge of $10.07 is significantly below the fully allocated embedded customer cost of $30.79 (Exhibit KEDNE/AEL-5). The Company proposes a customer charge of $16.98, which is one-third of the difference between the current customer charge and the fully allocated customer costs. Because the customer charge is not set at the fully allocated costs, the proposed charge retains an intra-class subsidy. However, the partial move toward the fully allocated costs serves the objective of rate continuity, particularly for the lower-use customers in the rate class.

Also, to maintain rate continuity the Company made an additional adjustment. Specifically, the Company shifted approximately $8.04 million of the off-peak embedded cost recovery to the peak period, where it is collected over the larger peak-period volumes. The total revenue requirement remains the same, but this change is required to ensure that the peak rates are equal to the off-peak rates. This change is consistent with the rate design approved by the Department in D.P.U. 96-50.

The Company also maintained the peak-period block break at 150 therms and the off-peak block break at 30 therms to keep the number of bills in the headblock close to 50%. The peak and off-peak tailblock rates of $0.1974 per therm are set at marginal cost.

Q. Do you have any general comments on the design of the commercial/industrial rates?

A. Yes. Examination of Ms. Leary's cost studies show a wide variation in the percentage increase among the commercial and industrial ("C&I") rate schedules. In some cases, using these amounts would result in substantial differences in bill impacts among the C&I rate classes. To mitigate these bill impacts, the Company re-allocated $800,000 from the G-54 class to the revenue requirement for the G-53 class ($500,000) and the G-43 class ($300,000). This follows the Department's directives in D.P.U. 96-50.

Q. Please comment on the C&I rates, beginning with G-41.

A. The Company made two determinations for continuity reasons with respect to the G-41 rate. First, although the fully allocated embedded customer costs are $54.00 (Exhibit KEDNE/AEL-5), the Company established a $33.55 customer charge, representing a 44% increase from the current customer charge of $23.33, and one-third of difference between the current customer charge and the charge using the embedded cost. Second, the Company moved the recovery of $1.65 million from the off-peak to the peak period to enable the establishment of flat volumetric rates of $0.3765 for the peak and $0.3267 for the off-peak periods for this class.

Q. Were any similar adjustments made for continuity reasons with respect to rate G-42?

A. Yes. The Company increased the customer charge from $40.83 to $57.58, rather than moving to the fully allocated embedded customer costs of $91.08. Further, the Company moved $200,000 from the off-peak to the peak period to establish flat volumetric rates for the peak and off-peak periods. The resulting rates are $0.2456 for the peak and $0.2361 for the off-peak.

Q. Please explain the rate structure of the G-43 rate class.

A. In designing the rates for this class, the Company increased the customer charge from $116.65 to $139.28, which is below the fully allocated embedded customer charge of $184.33. To maintain the flat volumetric rate design for the peak and off-peak rates, the Company shifted $1.0 million from the peak to the off-peak revenue requirement. The resulting rates are $0.2019 for the peak period and $0.1799 for the off-peak period.

Q. Please discuss the G-44 rates.

A. In designing the rates for this class, the Company increased the customer charge from $478.73 to $548.67, which is below the fully allocated embedded customer charge of $688.56. Like the other 40-series rates, this rate class has flat peak ($0.1966) and off-peak ($0.1784) volumetric rates. In this case, the Company is proposing to eliminate the demand charge that currently exists in this rate design in the interest of rate equity.

In the current rate design, each customer has a Maximum Daily Contract Quantity ("MDCQ"), which is the component that is applied to determine the monthly demand charge for billing purposes. Because cost-effective gas demand meters are not available, the MDCQ is calculated using customer consumption data from the peak month of the prior corresponding season, adjusted to determine a daily quantity. When a peak month is extremely cold, the customer's consumption increases, thereby increasing the MDCQ, which means that the customer will pay a higher demand charge throughout the future corresponding season even if the future season is warmer and consumption is less. Faced with high bills, customers sometimes will seek to shift into a different rate class to avoid paying the higher demand charge. In addition, because the customer is always paying a rate that is based on the prior period peak or off-peak period, the customer is not receiving an accurate price signal to guide current consumption decisions. Lastly, customers find the rate design confusing and complain about paying higher bills in the current year for consumption in the prior year. As a result, the Company is proposing to establish a volumetric rate that simplifies the rate structure and sends the customer proper price signals by billing customers based on their consumption in the current season.

Q. Please discuss the 50-series, C&I High Load Factor rates.

A. As with the rate classes previously discussed, the Company did not impose the fully allocated embedded customer charge for the 50-series rates for rate continuity purposes. Therefore, customer charges are designed to match the structure used for the same size customers in the 40-series. The G-51 customer charge was increased from $23.34 to $29.47, the G-52 customer charge was increased from $40.84 to $50.67, the G-53 customer charge was increased from $116.77 to $126.60, and the G-54 customer charge was increased from $478.31 to $587.14.

In addition, the Company designed the rates in the 50-series as flat volumetric rates rather than "block" rates. This simplifies the rate structure and parallels the rate design for the 40-series rate classes. For each rate class in the 50-series, the flat rate exceeds the marginal cost for that class. Also, for the G-53 rates, the Company moved $300,000 from the peak period to the off-peak period to maintain flat volumetric rates for each period. Finally, as in the case with rate G-44, the Company is proposing to eliminate the demand charge that currently exists in rate G-54 and establish a volumetric rate that simplifies the rate structure, sends the customer proper price signals and enhances rate equity.

Q. Please explain the Company's proposal with regard to the 60-series rate classes.

A. The Company is proposing to eliminate the 60-series rate classes and to combine the customers and volumes associated with these classes with the similar sized 50-series rate classes. The Company is proposing this change because the 50-series and 60-series rate classes are redundant in that the current rate structure is identical for both rate series. For example, the customer charge, tailblock break point, and the headblock and tailblock rates for the G-61 class are the same as those for the G-51 class. Further, the availability clauses for 50-series rates are equally applicable to customers currently on the 60-series rates. The 50-series rates are available to customers that consume less than 70% of their annual load in the peak period. In comparison, the 60-series rates are available to customers that consume less than 20% of their annual load in the peak period. All of the customers currently in the 60-series rate class are eligible for the corresponding 50-series rate class, and would be charged the same rates. Therefore, the Company is proposing to eliminate the 60-series rates because they are unnecessary and provide no benefit to customers.

Q. Please describe the development of the Street Lighting rate.

A. The Street Lighting Rate (G-7), is developed as shown on Exhibit KEDNE/ALS-4. The total revenue requirement for the rate class from the COSS represents the fixed revenues to be recovered from this class. Therefore, the Company calculated the monthly fixed charge per lamp based on the number lamps on the Company's system. For purposes of billing the CGA and LDAC, the Company calculated the therms per hour per lamp factor for the running charge component of the rate.

Q. Please explain the development of the Residential Gas Lamp rate (G-17).

A. This rate was developed in a fashion somewhat different than the street lighting rate. The total revenue requirement, representing the fixed charges, was developed in the COSS. However, because the fully allocated embedded costs indicate an increase that would triple the rate for this class, the Company instead applied the average base-rate percentage increase for all classes to G-17 rate to determine the proposed rates.

Q. How will the Company implement the annual price-cap rate changes in the base-rate schedules?

A. As discussed in the testimony of Mr. Bodanza, the Company is proposing to implement annual price changes in the same fashion as it has during the period of the prior performance-based ratemaking plan. This means that, absent competitive considerations or changes in cost allocation, revenues for each class will generally increase by the percentage rate calculated for the price path. The Company proposes to increase the customer charges up to the embedded cost levels over the life of the plan. The remaining revenues will be collected in volumetric charges.

Q. Have you prepared customer bill impacts showing the affects of the proposed rates on the customers?

A. Yes. Exhibit KEDNE/ALS-4 shows the customer bill impacts that result from changing current rates to those proposed in this filing. These impacts include both base rates and gas costs, using a peak CGA factor that is the average of the CGA prices in effect for the period November through April 2002-03. For the off-peak period, the Company used the CGA that will become effective as of May 1, 2003.

Q. Have you prepared tariff sheets reflecting the pricing changes discussed in your testimony?

A. Yes, a complete set of tariff sheets is attached as Exhibit KEDNE/ALS-7.

IV. WEATHER NORMALIZATION CLAUSE

Q. Please describe the Company's weather normalization proposal.

A As discussed in the testimony of Mr. Bodanza, the Company is proposing to establish a Weather Normalization Clause ("WNC") designed to minimize fluctuations in customer bills due to weather volatility. The Company's revenue requirement, in terms of both the underlying costs and revenues, is recovered based on "normalized" sales volumes, or the sales volumes projected under normal weather conditions. This has two interrelated ramifications when actual weather is colder or warmer than normal.

First, when actual weather differs from normal weather, the Company's actual firm sales volumes will differ from the billing determinants used to design distribution rates, thereby causing the Company to recover a greater or lesser amount of revenue, depending on whether it is warmer or colder than normal. In addition, relatively warmer or colder weather will affect the volumes of gas consumed by customers. As a result, in the period where weather is colder than normal and customer consumption is greater than expected, customers experience increases in their total bills and the Company recovers a greater amount of revenue. Conversely, when weather is warmer than normal and customer consumption is lower than expected, customers have relatively smaller bills and the Company recovers a lower amount of revenue.

This dynamic is exacerbated because the rate-design methodology utilizes: (1) embedded cost-allocation formulas that assign 65% of non-gas costs and revenues to the peak period; and (2) a marginal-cost/rate design methodology that assigns 18% of the revenue recovery to the tailblock. The combination of assigning a large portion of costs to the peak period, and recovering those costs in the variable portion (tailblock) of the distribution rate, makes both net revenues and customer bills particularly sensitive to weather. As discussed in the testimony of Mr. Bodanza, the Company's proposed WNC would stabilize customer bill and revenue fluctuations that result from weather volatility. Exhibit KEDNE/ALS-6 presents the Company's proposed tariff to implement the WNC.

Q. Please explain how the WNC will work.

A. Each billing cycle, during the peak period November through April, the Company will adjust customer bills to account for any variation in weather that deviates by more than 2% of normal during that cycle. Normal weather is defined according to Department precedent as the most recent 20-year average of degree-days for the Company's service territory. In this case, the Company has used the 20-year period 1983 through 2002, inclusive. The steps involved in developing the WNC are as follows:

- First, the Company calculates the actual degree days during the billing cycle;
- Next, the Company calculates the normal degree days for the same cycle;
- Then, the Company calculates the percentage difference between actual degree days and normal degree days;
- If the percentage difference is less than plus or minus 2%, no adjustment is made;
- If the percentage differs from normal by greater than 2%, the Company subtracts 2% from the percentage difference to determine the WNC adjustment percentage;
- Next, using the base load and heating increment information associated with each customer account, the Company determines the portion of the customer's use that is temperature sensitive;
- The Company then multiplies the WNC adjustment percentage by the portion of the customer's total use that is temperature sensitive to determine the customer-specific WNC adjustment percentage;
- The customer-specific WNC adjustment percentage is then multiplied by the customer's tailblock rate to determine the WNC adjustment for that customer;
- This WNC adjustment then becomes the tailblock rate for the customer for that billing cycle and is used to produce the customer's weather adjusted bill for that month.

An important feature of this methodology is that customer bills are adjusted on a real-time basis, i.e., as the bills are rendered, thereby providing timely relief from weather variability affecting customer bills in the winter period. Over time, it is reasonable to assume that weather will be normal and that the short-term pluses and minuses will offset each other. Therefore, on average, the WNC will help stabilize customer bills and provide needed relief during winters characterized by colder-than-normal weather and relatively higher bills.

Q. Will the Company update the Department as to the factors that have been used in the WNC adjustment calculation?

A. Yes. The Company proposes that, in each annual PBR compliance filing, it will include an update indicating: (1) base load factors for each rate class; (2) heating increments for each rate class; and (3) tailblock margin for each rate class.

Q. What is the purpose of the 2% deadband?

A The Company is proposing a 2% deadband because it allows for a reasonable level of variability in customers bills when weather is relatively close to normal, while smoothing the extreme variability in customer bills that results when weather deviates more significantly from 20-year normal levels.

Q. Which customer classes would be subject to the WNC adjustment?

A. The WNC adjustment would apply to rate classes R-1, R-3, G-41, G-42, G-43, G-44, G-51, G-52, G-53 and G-54 during the peak period November through March.

Q. Does this conclude your testimony?

A. Yes.